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Abstract

In this paper we describe a fundamental structure for the transmission provider (TP) composed of the independent transmission company (ITC) and the system operator (SO). Under the proposed structure, the ITC and the SO are two entities working cooperatively to carry out the functions of the TP. The entities are differentiated through the ownership and the operational authority. Roughly speaking, the ITC owns the regional network, provides various services connected with the longer term (physical and financial) energy trade, and carries out the related functions including making investment decisions. The SO, on the other hand, has the operational authority over the entire network, provides many services linked to the shorter term (physical) energy trade, and carries out the associated functions including managing transmission congestion.

At the minimum, there are three groups of entities and three infrastructures important for a proficient management of the electric power network. The three groups refer to the regulator, the TP composed of the ITC and the SO, and the market participants consisting of generators, loads and marketers. The three infrastructures are spot market for energy balancing, forward markets for transmission and the open access same-time information system (OASIS). This paper describes the role of TP with an emphasis on the ITC and the forward markets for transmission.

It is shown that the new structure is essential for fostering the operation and planning of the electric power network by the TP with a desirable level of efficiency and reliability while supporting the regional energy markets.

I. Introduction

At the initial stage of electricity restructuring in early 90's there were various reports estimating the expected improvements in efficiency with the introduction of competition. They range from the short-term effects; savings of $24 billion to $80 billion per year, or 10 percent of 40 percent off the average electric bill, to the long-term consequences; technological innovations and increase in reliability. Indeed the experience from the deregulation of telecommunication industry gave every indication that the similar benefits would be capitalized by simply dividing vertically integrated utilities into generation, transmission and distribution sectors and allowing competition to take place in generation sectors through divesture.

However, the reality of it is that the electricity restructuring process has been met with only few successes, far below the expectations, as well as with a couple of orders of magnitude more number of difficulties than that of telecommunication industry. Did people just expect too much? In order to answer this question, we must look into the assumptions that often follow with the introduction of competition.

The competition forces market participants to be more aware of their own profits. In simple economics terms, the profit consists of two parts: revenue and cost. From the supplier point of view, an increase in profit can be achieved either by decreasing costs or by increasing revenues. A decrease in costs is possible when the supplier can achieve higher efficiency from her existing plants, thus reducing the associated O&M costs. An increase in revenues is possible when the supplier can expand her customer basis.[1] From the consumer point of view, an increase in profit is directly related to finding a supplier who can offer the same quality goods at lower prices.

In the electricity industry the suppliers are the generators. Their costs constitute of various parts depending on the particular technology used to produce (electric) power; running a nuclear plant, for example, requires the incursion of (plutonium) fuel costs, O&M costs, fixed costs, etc. Their revenues are the product of (electric) energy produced and corresponding electricity prices. The consumers, on the other hand, consist of distribution companies, electric cooperatives, market aggregators and in some instances, large industrial users. Their

[1] Throughout the chapter we assume no supplier has the market power so that raising her price to increase the revenue is not an alternative.

costs are the electricity prices at which their loads are served.

In many parts of U.S. the energy market is structured in a way that there is no direct access between suppliers and consumers. As far as suppliers are concerned, their only customer is the transmission provider (TP), and for consumers, the TP plays the role of the sole supplier. This is due to the peculiar nature of electricity. Because there is no good practical means of storing electricity, the supply and the demand must be balanced continually. Plus, unlike in the telecommunication industry where a failure to execute a transaction results in "busy" signal, a failure to balance the system can result in system-wide blackout which can amount to astronomical figures in terms of losses. Therefore, the TP who is also the system operator must lead the coordinating effort in meeting the supply and demand with the scarce transmission capacity at times, and the easiest possible way to do so is by being in the middle and acting as the sole purchaser to suppliers and the sole seller to consumers.

Unfortunately in this market setup, the competition is always in a confined scope. In the short-run without the direct access which allows an active interaction between suppliers and consumers, there is a limit to how much suppliers are willing to lower the prices in order to expand their customer basis. More importantly, however, in the long-run no direct access means no customer choices, which is often the key to technological innovations. To make the matters worse, the market is structured so that in connecting suppliers and consumers, the TP does not assume any financial involvements due to her monopolistic stance. In order to overcome this dire situation, the current electricity market must undergo a little evolutionary steps so that there is a proliferation of direct access in the form of bilateral contracts.

Bilateral contracts are financial contracts written on the physical underlying of energy transfer involving only a subset of suppliers and consumers without the TP.[2] As with other financial contracts, there are number of risks associated with bilateral contracts. The two major ones are the risks associated with future electricity prices and with transmission capacity. Because the participants enter into the contracts in advance, they are exposed to risk of future energy prices set by the TP on which the strike price is determined. This is, however, well understood in the world of finances, and there are many financial tools to deal with such risk. When the transmission capacity is scarce due to high level of demand, energy

[2]As a financial contract the bilateral contract needs not to be limited to physical transfer. However, for simplicity without loss of generality we consider only the contracts associated with physical transfer.

transfers from certain parts of the transmission system to certain other parts are simply not possible or extremely uneconomical. Due to the high level of complexity in mapping financial bilateral deals with physical transfer, this risk is extremely hard to measure and has relatively few financial tools that can be complementary.

With the presence of bilateral contracts (and various other financial deals on transfer of electricity), the TP faces not only increase in operational difficulties with added complexity, but also a conundrum in planning as the market need changes far more rapidly than the transmission system can evolve. This has serious consequences in reliability as evidenced by recent system-wide blackouts. In the subsequent sections, we present a particular market structure that equips the TP with market-based solutions to conducting energy market with large quantity of bilateral transactions. This market structure also permits TP to become actively involved in market process despite the monopolistic stance. By allowing TP to pursue profit, it is shown that the transmission expansion problem can also be solved in an efficient way as intended with the introduction of competition.

II. Functions and services

Figure 1 shows the overall market composition under the newly proposed structure for the transmission provider (TP) composed of the independent transmission company (ITC) and the system operator (SO). Roughly speaking, the ITC owns the regional network, provides various services connected with the longer term (physical and financial) energy trade, and carries out the related functions including making investment decisions. The SO, on the other hand, has the operational authority over the entire network, provides many services linked to the shorter term (physical) energy trade, and carries out the associated functions including managing transmission congestion.

The principal functions of the TP include making investment decisions into transmission, making expenditure decisions into the control effort and the maintenance effort and choosing pricing decisions for congestion management. These functions are subject to a strict regulation by the regulator because the TP typically exists as a natural monopoly due to a high degree of economies of scale and of economies of scope related to the electric power network. Here we consider a particular form of regulation called, the *price-cap* regulation (PCR). Compared to other regulation schemes the PCR is believed to be best suited for

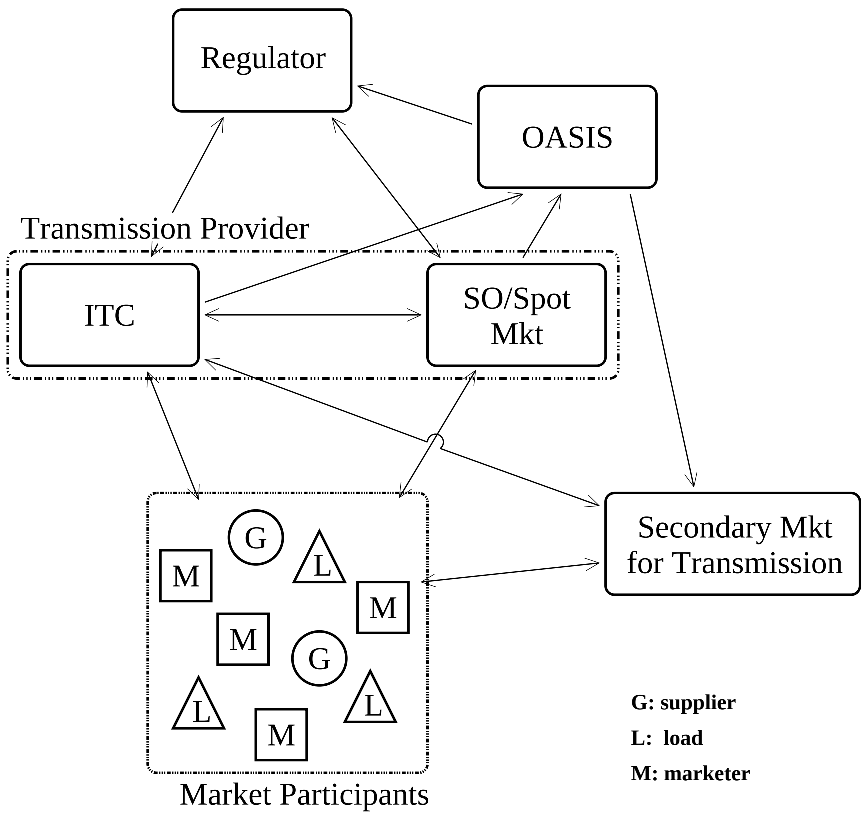

Fig. 1. Overall market composition under the newly proposed structure

inducing high level of economic efficiency and has been successfully tested in the telecommunication industry [7]. We begin by examining the necessary modifications to the PCR scheme, employed in the telecommunication industry, for the application to the TP.

A. Possible price-cap regulation (PCR) to be imposed on the proposed structure for the transmission provider (TP)

Through the restructuring process the electricity is provided to the load by the generators through the market mechanisms. The utility functions of the loads and the cost functions of the generators are revealed in the form of demand functions and supply functions respectively through their overall market activities. We denote the demand and the supply functions as $D_{d_j}(Q_{d_j}[k], k)$ and $S_{g_i}(Q_{g_i}[k], k)$.

Then, from the perspective of the consumer, each load d_j chooses the optimal level of its consumption, $Q_{d_j}[k]$ at each hour k in the spot market based on the maximization function, often referred to as *competitive consumer surplus* function, given as the following:

$$Q^{\star}_{d_j}[k] = \arg\max_{Q_{d_j}[k]} \mathcal{E}\left\{\int_{\tilde{Q_{d_j}}[k]=0}^{Q_{d_j}[k]} D_{d_j}(\tilde{Q_{d_j}}[k],k)d\tilde{Q_{d_j}}[k] - \rho_{e,d_j}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)\cdot Q_{d_j}[k] \right. \quad (1)$$

$$\left. -\hat{\rho}_{t,d_j}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)\cdot Q_{d_j}[k]\right\}$$

where $\rho_{e,d_j}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)$ and $\hat{\rho}_{t,d_j}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)$ are the prices for the energy and transmission portions of electric services at load d_j, respectively.

Spot market refers to the short-term market for a physical commodity, in this case electricity. In the spot market for electricity, the prices reflect the value of power that is available to meet the near real-time demand, within a time scale of a day or just a few hours. For simplicity without the loss of generality we consider that the spot market is conducted on an hourly basis in order to match the demand and supply for electricity.

Mirroring the formulation of the competitive consumer surplus function in Eq. (1), from the perspective of the supplier, each generator g_i chooses the optimal level of its production, $Q_{g_i}[k]$ at each hour k in the spot market based on the maximization function, often referred to as *competitive supplier surplus* function, given as the following[3]:

$$Q^{\star}_{g_i}[k] = \arg\max_{Q_{g_i}[k]} \mathcal{E}\left\{\rho_{e,g_i}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)\cdot Q_{g_i}[k] - \hat{\rho}_{t,g_i}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)\cdot Q_{g_i}[k] \right. \quad (2)$$

$$\left. -\int_{\tilde{Q_{g_i}}[k]=0}^{Q_{g_i}[k]} S_{g_i}(\tilde{Q_{g_i}}[k],k)d\tilde{Q_{g_i}}[k]\right\}$$

where $\rho_{e,g_i}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)$ and $\hat{\rho}_{t,g_i}(\mathbf{Q_D}[k],\mathbf{Q_G}[k],k)$ are the prices for the energy and transmission portions of electric services at generator g_i, respectively.

The quantity dependent pricing for transmission capacity is of particular importance [6]. On one hand, when the price for transmission capacity is set too low, some parts of the network may experience what is often referred to as the transmission congestion at the peak demand hours. The electric power flow on the transmission lines are limited by the transfer capacity through the dispatch in generation and load due to the inability to direct transfer of electricity through a particular path in the electric power network. The transmission congestion refers to the inability to dispatch additional generation from certain generators within

[3]The actual competitive supplier surplus function is the decentralized unit commitment problem formulated in [1]. However, we make the assumption that the only available information regarding the supplier is his supply function at the spot market, and when the cost function of supplier is revealed in the spot market, the unit commitment decision is already internalized in its supply function.

the system due to transmission line limits. Mathematically, the transmission congestion on line l is expressed as the following:

$$F_l(\mathbf{Q_G}[k], \mathbf{Q_D}[k]) > F_l^{\max}(\mathbf{F}[k], K_l[k], e_{tech}[k], e_m[k]) \tag{3}$$

where

$F_l(\mathbf{Q_G}[k], \mathbf{Q_D}[k])$	: electric power flow through line l as a function of the dispatch in generation, $\mathbf{Q_G}[k]$, and load, $\mathbf{Q_D}[k]$ at hour k
$F_l^{\max}(\mathbf{F}[k], K_l[k], e_{tech}[k], e_m[k])$	: operational limit on power transfer through line l as a function of operating condition, $\mathbf{F}[k]$, the thermal rating on the line, $K_l[k]$, the control effort, $e_{tech}[k]$, and the maintenance effort, $e_m[k]$

Thus, the prices for transmission capacities, $\hat{\rho}_{t,d_j}(\mathbf{Q_D}[k], \mathbf{Q_G}[k], k)$ and $\hat{\rho}_{t,g_i}(\mathbf{Q_D}[k], \mathbf{Q_G}[k], k)$ need to be chosen at an adequate level in order to give incentives for avoiding transmission congestion. On the other hand, when the price for transmission capacity is set too high, the network is under-utilized. Thus, the pricing of transmission, the congestion pricing, becomes significant in achieving economic efficiency while conforming to operational limit on power transfer through each transmission line.

Since the energy portion of the electricity is provided through market mechanisms, under the perfect competition with free entry assumption, the corresponding price at each bus is identical throughout the network, i.e., $\rho_e[k] = \rho_{e,d_j}[k] = \rho_{e,g_i}[k]$. Then, the decentralized optimization by all loads and generators in Eqs. (1) and (2) yield the same solution to following optimization problem:

$$\begin{aligned}
[\mathbf{Q_G}^\star[k], \mathbf{Q_D}^\star[k]]' = \arg \max_{\mathbf{Q_G}[k], \mathbf{Q_D}[k]} \mathcal{E} \Bigg\{ \sum_{d_j} \Bigg(\int_{\tilde{Q}_{d_j}[k]=0}^{Q_{d_j}[k]} D_{d_j}(\tilde{Q}_{d_j}[k], k) d\tilde{Q}_{d_j}[k] \\
-\rho_{t,d_j}(\mathbf{Q_D}[k], \mathbf{Q_G}[k], k) \cdot Q_{d_j}[k] \Bigg) - \sum_{g_i} \Bigg(\int_{\tilde{Q}_{g_i}[k]=0}^{Q_{g_i}[k]} S_{g_i}(\tilde{Q}_{g_i}[k], k) d\tilde{Q}_{g_i}[k] \\
+\rho_{t,g_i}(\mathbf{Q_D}[k], \mathbf{Q_G}[k], k) \cdot Q_{g_i}[k]) \}
\end{aligned} \tag{4}$$

subject to

$$\sum_{g_i} Q_{g_i}[k] = \sum_{d_j} Q_{d_j}[k] : \qquad \lambda[k] \tag{5}$$

$$Q_{g_i}^{\min}[k] \leq Q_{g_i}[k] \leq Q_{g_i}^{\max}[k] : \qquad \eta_{g_i}[k] \tag{6}$$

$$F_l(\mathbf{Q_G}[k], \mathbf{Q_D}[k]) \leq F_l^{\max}[k] : \qquad \mu_l[k] \tag{7}$$

where ρ_{t,d_j} and ρ_{t,g_i} replace $\hat{\rho}_{t,d_j}$ and $\hat{\rho}_{t,g_i}$ respectively so that the *penalty* associated with the transmission congestion is expressed separately through the constraint defined in Ineq. (7) under the centralized optimization.

Let f_{l,d_j} denote the flow on line l related to load d_j derived by decomposing the apparent flow $F_l[k]$ into the flow corresponding to supplying the demand at the same load, $Q_{d_j}[k]$. Then, f_{l,d_j} can be computed using the following expression:

$$f_{l,d_j}[k] = F_l(\mathbf{Q_G}_{d_j}[k], \mathbf{Q_D}_{d_j}[k]) \tag{8}$$

where $\mathbf{Q_G}_{d_j}[k]$ and $\mathbf{Q_D}_{d_j}[k]$ are given by:

$$\mathbf{Q_G}_{d_j}[k] = \left(\frac{Q_{d_j}[k]}{\sum_{d_j} Q_{d_j}[k]} \right) \cdot \mathbf{Q_G}[k] \tag{9}$$

$$\mathbf{Q_D}_{d_j}[k] = [0, \cdots, Q_{d_j}[k], 0, \cdots, 0]' \tag{10}$$

Typically, for notational convenience, given a transmission line l connecting buses i and j, an arbitrary direction ij is defined. According to this direction the computed flow is either positive if the flow is from bus i to bus j, or negative otherwise. Let $q_{l,d_j}^{+}[k]$ and $q_{l,d_j}^{-}[k]$ denote the positive and the negative directional flow of $f_{l,d_j}[k]$, i.e.,

$$q_{l,d_j}^{+}[k] = \begin{cases} f_{l,d_j}[k] & \text{if } f_{l,d_j}[k] \geq 0 \\ 0 & \text{otherwise} \end{cases} \tag{11}$$

$$q_{l,d_j}^{-}[k] = \begin{cases} -f_{l,d_j}[k] & \text{if } f_{l,d_j}[k] \leq 0 \\ 0 & \text{otherwise} \end{cases} \tag{12}$$

Suppose the transmission charge on market participants are given by

$$\rho_{t,d_j}(\mathbf{Q_D}[k], \mathbf{Q_G}[k], k) \cdot Q_{d_j}[k] = \sum_l \left[(\rho_t[k] + \mu_l)\, q_{l,d_j}^{+}[k] + (\rho_t[k] - \mu_l)\, q_{l,d_j}^{-}[k] \right] \tag{13}$$

Then, the price-cap regulation (PCR) scheme can be created by imposing the maximum allowed transmission charges on flow, i.e.,

$$\hat{\rho}_t[k] \leq \hat{\rho}_t[n] \tag{14}$$

$$\mu_l[k] \leq \mu_l[n] \tag{15}$$

where $\hat{\rho}_t[n]$ and $\mu_l[n]$ are the ceiling prices defined under the PCR [9]. Sometimes $\hat{\rho}_t[k]$ and $\mu_l[k]$ are referred to as *ex ante* flow tax and congestion cost, respectively.

Once the demand and the supply functions are known for each hour, then the actual amount of the capacity to be distributed to individual participants can be readily computed by solving the optimization problems in Eq. (4). If all energy trades among market participants were conducted through the spot market for energy, then the TP could discover the demand and the supply functions of the market participants by offering transmission capacity through the hourly congestion pricing. That is to say, the spot market mechanisms alone would be adequate in dealing with the loads and the generators in the market under the PCR scheme defined here. However, the market participants are engaged in various market activities to offer and to acquire electricity according to their evolving needs. Most of these market activities are initiated as purely financial and thus actually have no immediate impact on the network operation. As some of these activities become physical exchanges requiring the actual transport of electricity from a generation source to a load sink, the accompanying transmission capacity needs to be available for purchase so that the participants can carry out these physical exchanges. This is where a TP may gain considerable understanding of the demand and the supply function of the market participants by offering the transmission capacity matching the materializing physical exchanges. It should be recognized that *most* financial contracts turn into physical exchanges at the time scales much longer than hourly. This is due to, for instance, the unit commitment of generators being typically done on a weekly basis rather than hourly basis [1]. Plus, not every financial contract requires the same type of transmission capacity services. Consequently the TP needs to offer more network services than just the hourly congestion pricing to participate in every phase of energy market activities.

B. Changing role of the transmission provider (TP)

There are a couple of important features to be considered regarding the ability of a TP to offer transmission capacity as the needs arise.

The first is related to installing confidence in the market mechanisms by which electricity is provided from the generators to the loads. The core of market for a commodity is that there is a set of pre-determined rules and that if the participants enter into various contracts with one another following these rules, then the actual exchange of commodity takes place according to these contracts. Unless this very core is satisfied, there is no binding principle of economics under which competitive market functions would provide the commodity in question with a desired level of efficiency. Thus, this requires a market mechanism by which the TP can offer the network capacity and the market participants can acquire the transmission to match their physical exchanges.

The second is related to establishing a process for the TP to estimate the market participants' overall demand for network capacity. The only viable process for such estimation is by allowing the TP to also actively participate in the market process so that there is a constant communication between the market participants and the TP concerning the transmission network. Thus, this requires a clear market mechanism of the TP offering to the market participants the desired transmission services in the energy market without compromising the integrity of the market while preserving the monopoly status.

Clearly this implies the new role of a TP compared to that under the vertically integrated utility structure or to that under the current development [11]. Figure 2 shows this changing role of a TP in the evolving electric power industry. The multilateral transaction model,

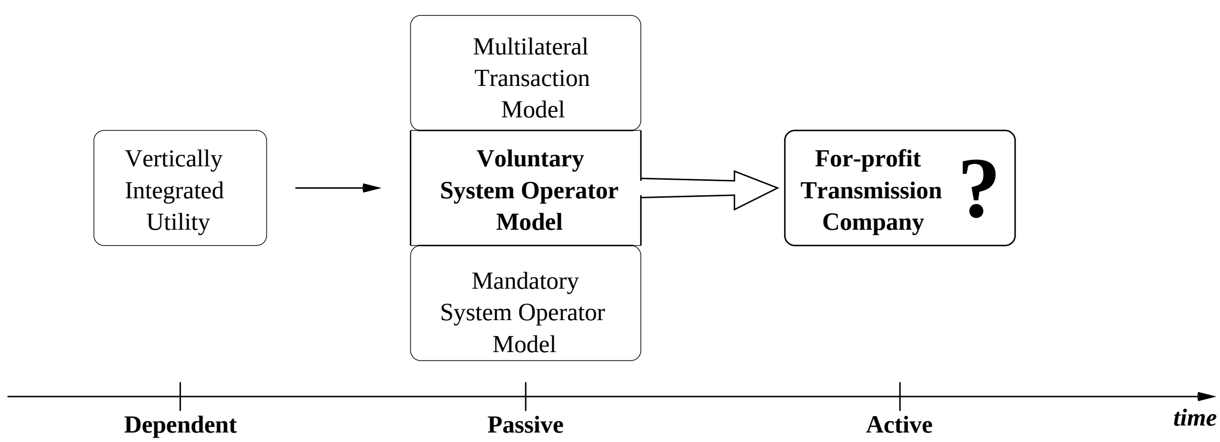

Fig. 2. Changing Role of Transmission Provider

voluntary system operator model and the mandatory system operator model refer to the underlying market structure [6]. In the *dependent* phase a TP functions as part of a vertically integrated utility. In the *passive* phase a TP stands alone and oversees overall market activities under the rate-of-return regulation. The market participants are required to *submit*, in the form of bids, their intended use of the system to a TP and, based on that information, the TP allocates the existing transmission capacity following the strict rules set by regulators. The TP assumes no financial responsibilities and has minimal interactions with market participants while the regulator is responsible for approving the transmission charge thus is responsible for the expansion of the network. In the *active* phase a market mechanism is set up so that a TP participates in every phase of energy market activities. The TP actively *learns* the desired usage of the network by the participants rather than passively accepting their intended usage expressed in the submitted bids.

In the following sections we describe the minimum network services to be provided by a TP at three different time scales of the long term (longer than one year), the intermediate term (a year to a season), and the short term.

III. Long term network services

The long term network services refer to any *point-to-point* network capacity offered through the long term transmission contracts by the ITC in increments of a year starting from the year following the current one. These services are provided without any direct regulation imposed on the ITC by the regulator.

The market participants enter into various forward contracts ranging from 1 year to 5 years future in time for hedging purposes. Since the exact contents of these contracts are not of particular interest here, we make a simplifying assumption that there are two types of long term contracts, namely long term hub-based contracts and the long term point-to-point contracts. The hub-based contracts are traded through an organized (power) exchange while the point-to-point contracts are entered into by two private parties. Here the hub refers to a financial institution responsible for conducting the exchanges, rather than a specific physical location within the network, where the energy contracts can be offered by specifying either the location of the source bus or the location of the sink bus without specifying the location of the counterpart buses. This is one of the unique features proposed in this paper that differentiates the electric power network economics from that of other commodities. For example, the hub in trading crude oil may refer to the warehouse location to which the physical commodity is delivered and received during the duration of the actual exchange [3].

The difference chiefly arises from the lack of practical means of storing electricity.[4]

The long term hub-based contracts specify at least the following four elements: the location of the source bus, g_i (or the sink bus, d_j), the amount of the energy to be delivered, Q_{g_i} (or Q_{d_j}), the price for the energy, $\rho_{g_i}(Q_{g_i})$ (or $\rho_{d_j}(Q_{d_j})$), and the duration of the contract, $[T_s, T_e]$. The variables, T_s and T_e, denote the beginning and the end point in time for the exchange, respectively. This information is usually publicly posted. Similarly, the long term point-to-point contracts include at least the following five specifications: the location of the source bus, g_i, the location of the sink bus, d_j, the amount of the energy to be delivered, $Q_{d_j-g_i,e}$, the price for the energy, $\rho_{d_j-g_i,e}$ and the duration of the contract. This information is usually proprietary to the two parties entering into the contract.

Suppose there are N_B buses in the network.[5] Then, the ITC may offer up to $2N_B(N_B-1)$ long term transmission contracts[6] for any given time. The coefficient of 2 accounts for the dual directionality of flow in point-to-point exchanges. The price at which each of these $2N_B(N_B-1)$ contracts is offered mainly depends on ITC's expectation of the transmission price to be charged for accommodating transport of electricity according to the amount of electricity, the location of generation source, the location of load sink and the duration of the exchange. The price of transmission contract for the same two locations in a point-to-point exchange may significantly differ depending on the direction of the exchange.

Then, the organized power exchange clears the hub-based contracts by matching the generation source with the load sink based on the bid price of each contract as well as the long term transmission contract offered by the ITC but without putting the obligation of purchasing the transmission contracts to the participants. It is up to the participants to purchase the transmission contracts to hedge their network related risks. In any case, the cleared bid pairs, g_i and d_j, are such that the bid price at generation source, ρ_{g_i}, and the bid price at load sink, ρ_{d_j}, satisfy the following relationship:

$$\rho_{d_j} = \rho_{g_i} + \rho_{d_j-g_i,t} \tag{16}$$

[4]It becomes clear later in the paper that not designating a physical location for the hub is important because the transmission charges are not additive under the PCR scheme described here.

[5]The number of buses in a network, N_B is always less than or equal to the sum of the number of generator buses, N_G and the number of load buses, N_D since some buses may connect both a generator and a load to the network.

[6]The number of possible contracts available is much lower depending on the demand for the contracts and on the level of data aggregation.

where $\rho_{d_j-g_i,t}$ denotes the price for the transmission contract offered for the proposed exchange between buses, g_i and d_j. Similarly, two private parties can enter into the point-to-point contract and may hedge their network related risks by purchasing the corresponding long term transmission contracts if available. Figure 3 shows the information exchange between the market participants and the ITC for the long term transmission contracts.

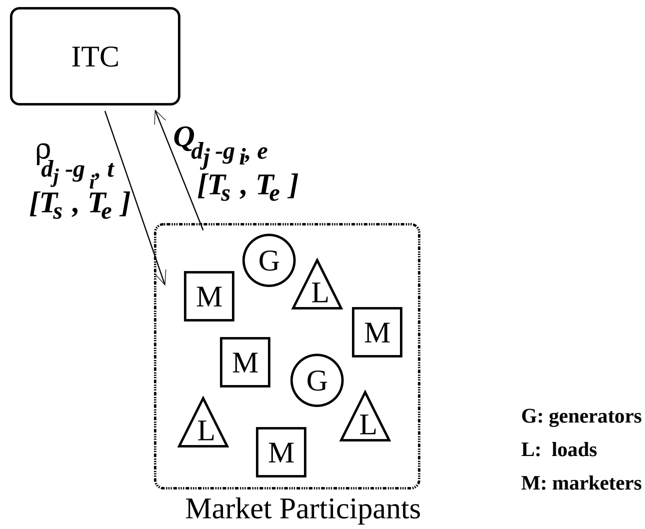

Fig. 3. The information exchange between the market participants and the ITC for the long term transmission contracts.

Under an organized power exchange scheme the ITC plays an important role of providing the critical information needed to conduct the financial (forward) market for entering into the long term energy contracts. In fact, based on the description above, the energy forward market cannot clear unless the matching long term transmission contracts are offered so that the price at the generation source and the price at the load sink are evaluated correctly accounting for the transmission charge as given in Eq. (16). Since the ITC is under no obligation to offer the long term transmission contracts, this may be a cause for alarm, at first glance. However, such concern can be addressed in two ways.

First, in case there is a high demand for certain point-to-point long term transmission contracts, it is in the ITC's best interest to offer those contracts because the ITC can collect the transmission revenue through the contracts while significantly reducing the associated volatility. The elements influencing the volatility are both financial and regulatory reasons. The financial reason is related to the intrinsically stochastic nature of the demand and supply functions. The regulatory reason is related to the PCR scheme considered in this paper. If there is no longer term transmission contracts offered by the TP, then all of network capacity is allocated through the spot market, and the transmission revenue is collected solely based on Eq. (13). Accordingly the transmission revenue may become extremely uncertain switching back and forth between the normal rate basis and the penalty rate basis in case the congestion prices experience high fluctuation. Plus, by offering the long term transmission contracts the ITC learns the demand and the supply functions of the loads and the generators over the longer period. Along with the reduced volatility in transmission revenue, this newly gained knowledge about the expected demand and supply functions is essential for carrying out the planning functions of the ITC, resulting in a high efficiency. Therefore, it is likely that the ITC would offer the long term transmission contracts.

Second, in case there are still no long term transmission contracts being offered by the ITC, any financial institution may continue to offer hedging contracts against the network related risks. The difference between the hedging contract being offered by the ITC and by the financial institutions is that the long term transmission contracts offered by the ITC are initially financial but they become the pseudo-physical transmission contracts offered by the SO within the year for which the contract is written whereas the ones offered by the financial institutions remain financial. This is because of the unique feature of the transmission contracts by the ITC, as being proposed here, that the participants who own the energy contracts with the matching transmission contracts, may claim the *priority* for utilizing the network without any obligations. We describe the aspects related to the physical transmission rights in more details in the subsequent section.

Note: Recently proposed hedging mechanisms by the SO's [4], [13] are quite misleading since no SO is in a position to compensate financially for not meeting a transmission contract. At present there is considerable confusion in this regard. Any risk related to the problems of simultaneous feasibility [4] with the FTR's proposed, for example, in [15] [16] are currently reflected in *ex post* customer charges, while the holders of FTR's, marketers, typically, are risk free! This is not a sustainable arrangement, and it is possibly the single strongest argument against SO's (not transmission owners) selling long term transmission contracts.

IV. Intermediate term network services

The intermediate term transmission services refer to *link-based* network capacity designed and offered by the ITC and the SO, respectively, through the intermediate term contracts up to the end of the year (or the season) at any time within the current year (or season).

A TP carries out most of its principal functions at the beginning of each year. That is to say, at the beginning of each year, the ITC makes the investment decisions for the network enhancement and the expenditure decisions for the maintenance procedures, and the SO determines the level of expenditure for the control effort, software in particular. These decisions are based on the knowledge gained by the ITC in offering the intermediate term transmission contracts and rest on the expertise obtained by the SO in operating the network in near real time. As two entities working cooperatively to carry out the functions of the TP, the ITC and the SO share their knowledge and the expertise so that they can maximize their overall profit under the PCR scheme considered in this paper. Once the decisions are made, the SO determines the anticipated available transmission capacity and the prices to be charged for the capacity with a reasonable accuracy for the entire year (or season) [12]. The ITC, then designs the intermediate term contracts for each transmission line within the year (or the season) to be auctioned off by the SO.[7]

Suppose there are N_T transmission lines in the network. Then, the ITC designs up to $2N_T$ intermediate term contracts for any given time[8] and makes them available for purchase through the SO by posting the respective (expected) prices, ρ_l^+ and ρ_l^-, for the contracts on each link per day by directions. Along with the prices, the SO posts the expected maximum flow limits, $F_l^{\max}$, and the so-called power transfer distribution factors (PTDF's) for the line l with respect to bus i, H_{li} [14]. The PTDF of line l with respect to bus i is the sensitivity vector of the line flow on the injection into bus i within the network.[9] Under the proposed ITC and the SO structure, it is required that the maximum flow limits, $F_l^{\max}$, and the PTDF's stay invariant throughout the year (or the season).

[7]This is a mere convenience arrangement since the SO is typically responsible for updating the OASIS. There is no particular reason why the ITC, for instance, can conduct the auction.

[8]Again the actual number of contracts available may be much smaller depending on the demand for the contracts and on the level of data aggregation.

[9]With the introduction of the PTDF, the operation of the electric power network is performed in the linearized regime as viewed by the market participants. This point becomes clear later in the paper.

Consider two prospective market participants with a proposed exchange of $Q_{d_j - g_i, e}$ between the generation source at bus g_i and the load sink at bus d_j over the period of time between t_s and t_e. Then, the participants may hedge their delivery-related risks completely by purchasing the intermediate term transmission contracts of the amount $H_{l(d_j - g_i)} \cdot Q_{d_j - g_i, e}$ on each line l in the network at the price of ρ_l^+ or ρ_l^- depending on the direction of the flow. Figure 4 shows the information exchange among the market participants, the ITC and the SO for the intermediate term transmission contracts. The participants with the long term

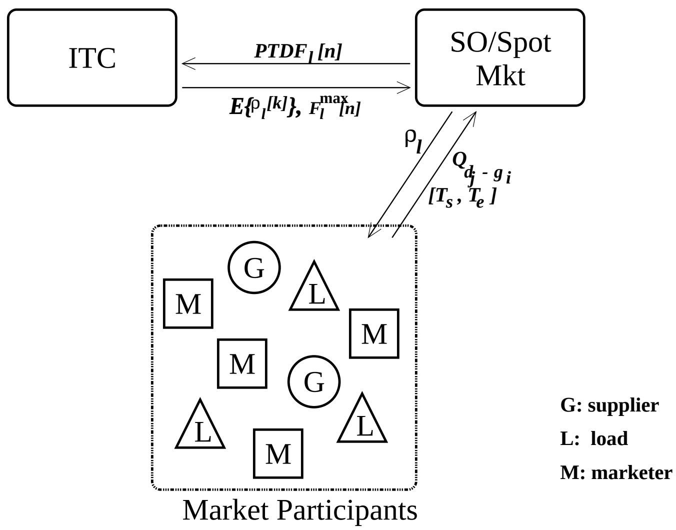

Fig. 4. The information exchange among between the market participants, the ITC and the SO for the intermediate term transmission contracts.

transmission contracts are required to convert the current year portion of the point-to-point contracts into the link based intermediate term transmission contracts at the beginning of the same year. The actual amount of the intermediate term transmission contract to be issued for converting the long term transmission contracts is based on the PTDF published by the SO at the beginning of the year.

Under the proposed structure, the ITC and the SO are *required* to offer the intermediate term transmission contracts so that the market participants may purchase these contracts to hedge their network related risks although the actual implementation of the services including the pricing is not subject to the regulatory oversight. This concurs with the notion that such contracts are essential for fostering the efficient use of the existing resources. Besides, the current trend in the regulatory structure is toward requiring the TP to offer some type of the longer term transmission contracts.[10]

Similar to the long term transmission contracts, it is in the ITC's best interest to offer those contracts because the ITC can collect the transmission revenue through the contracts while significantly reducing the associated volatility and learning the demand and the supply functions of the loads and the generators over the longer period.

The proposed intermediate term transmission contract belongs to the categories of both the physical transmission rights as well as the financial transmission rights. What distinguishes the physical transmission rights from the financial transmission rights is the priority in allocation of the network capacity assigned to the participants holding the transmission contracts [5]. Based on this distinction the intermediate term transmission contract proposed here is a physical contract because the owner of the contract has the priority in *utilizing* the network.

The actual mechanism under which the transmission capacity is allocated is as follows. At the beginning of each day, the SO identifies the holders of intermediate term transmission contracts with matching energy contracts having the generation capability. The available network capacity is then allocated to these holders first and the suppliers involved in the allocation process are scheduled for dispatch. If the transmission contracts are assumed to be sold in units of a day, the dispatch is performed for the entire day. The rest of intermediate term transmission contracts without the matching energy contracts become the financial transmission rights since the contract holder may use the contract to claim the portion of transmission revenue specified in the contract.

The residual transmission capacity after the initial allocation based on the intermediate term transmission rights is then distributed to the participants in the spot market and to the participants with bilateral energy contracts for energy without the matching transmission contracts. This process is described in the following section.

V. Short term network services

The short term network services refer to the allocation of residual transmission capacity in the spot market for energy. The related function of a TP is the near real time congestion

[10] The exact division of functions between the ITC and the SO in intermediate term network services is not critical. Various arrangements between the two are possible, as long as the TP as a whole (ITC & SO) perform the proposed function.

management as represented through the optimization problem defined in Eq. (4) associated with the TP under the PCR scheme described here. The actual allocation of residual transmission capacity in the spot market is based on this optimization problem modified to account for the portion of transmission capacity allocated previously to the participants with physical transmission rights. We assume that the SO conducts the spot market for energy.

Suppose the SO receives the bids from the loads, D_{d_j} and the generators, S_{g_i}, for trading energy in the spot market. In addition some other bids are made as the pairwise transactions, $B_{d_j - g_i}$, for implementing the bilateral trades without the matching intermediate term transmission contracts. Then, the SO solves the optimization problem given as the following:

$$
\begin{aligned}
[\mathbf{Q_G}^\star[k], \mathbf{Q_D}^\star[k], \mathbf{Q_B}^\star[k]]' = \arg \max_{\mathbf{Q_G}[k], \mathbf{Q_D}[k], \mathbf{Q_B}^\star[k]} \Bigg[& \sum_{d_j} \left(\int_{\tilde{Q_{d_j}}[k]=0}^{Q_{d_j}[k]} D_{d_j}(\tilde{Q_{d_j}}[k], k) d\tilde{Q_{d_j}}[k] \right. \\
& \left. - \sum_{l} \hat{\rho}_t^\star[n](q^+_{l,d_j}[k] + q^-_{l,d_j}[k]) \right) - \sum_{g_i} \int_{\tilde{Q_{g_i}}[k]=0}^{Q_{g_i}[k]} S_{g_i}(\tilde{Q_{g_i}}[k], k) d\tilde{Q_{g_i}}[k] \\
& + \sum_{b_{ij}} \left(\int_{\tilde{Q_{b_{ij}}}[k]=0}^{Q_{b_{ij}}[k]} B_{b_{ij}}(\tilde{Q_{b_{ij}}}[k], k) d\tilde{Q_{b_{ij}}}[k] - \sum_{l} \hat{\rho}_t^\star[n](q^+_{l,b_{ij}}[k] + q^-_{l,b_{ij}}[k]) \right) \Bigg]
\end{aligned} \tag{17}
$$

where q_{l,d_j} and $q_{l,b_{ij}}$, are the electric power flow on line l caused by meeting the demand Q_{d_j} at bus d_j from the spot market and by accommodating the bilateral exchange of $Q_{b_{ij}}[k]$ between buses i and j as requested by the users not participating in the spot market, respectively. The optimization problem is subject to the constraints in Eq. (5) and Ineq. (6) as well as modified transmission line flow limit given by:

$$
F_l(\mathbf{Q_G}[k], \mathbf{Q_D}[k], \mathbf{Q_B}^\star[k], \mathbf{F_{inter}}[k]) \leq F_l^{\max}[k] : \quad \mu_l[k] \tag{18}
$$

where $\mathbf{F_{inter}}[k]$ is the transmission capacity allocated to the participants with intermediate term transmission contracts with the matching energy contracts.

Figure 5 shows the information exchange among the market participants, and the SO for the allocation of residual transmission capacity in the spot market for energy. Unlike the long term network services and the intermediate term services, the short term network service is provided under the strict regulation. In the case of the PCR scheme considered here, this regulation is in the form of the ceiling prices represented as $\rho_t[n]$ and $\mu_l[n]$, as shown in Figure 5.

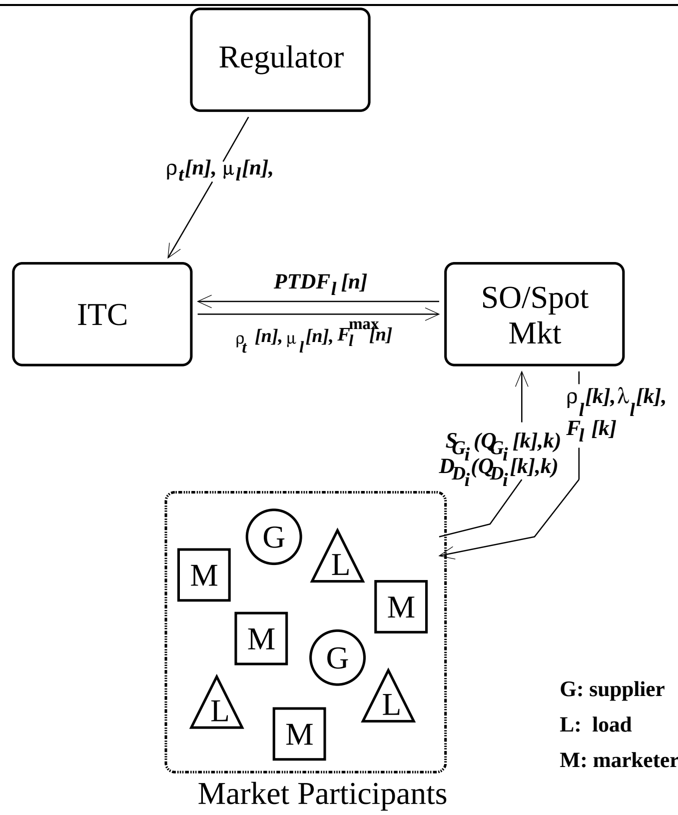

Fig. 5. The information exchange between the market participants and the SO for the allocation of residual transmission capacity in the spot market for energy

Once the ITC and the SO define the PTDF and the flow limits, then the SO allocates all of the residual transmission capacity available after distributing initially to the holders of the intermediate term transmission contracts with the matching energy contracts.

With the various services described above, the ITC and the SO can actively take part in the market process by offering these services to the market participants as they make various supply and demand decisions for energy at different time scales. First, the transmission capacity offered in the long term time scale is financial in nature and sends the signals useful for making planning decisions by the ITC. Next, the transmission capacity offered in the intermediate time scale is pseudo-physical in nature and sends the signals useful for deciding the expenditures into the control effort and the maintenance effort. Finally, the transmission capacity offered in the short term time scale is physical in nature and sends the signal useful for managing the congestion within the network by the SO. This is because the value of the network capacity is reflected in the price and the quantity at which these services are exchanged. The pricing of these services is, therefore, significant for discovering the demand

and the supply functions of the market participants. In the following section we discuss the pricing of the various services described above starting from the short term network services.

VI. Services and pricing

In pricing the network services, it is important to identify the constituent elements that limit the prices. Unlike the competitive firm whose marginal cost functions as both the upper bound and the lower bound for the pricing of his service, the regulated firm under the PCR scheme has only the upper bound on the price defined by the regulator. In the case of the PCR imposed on the TP here, there are two price elements subject to ceiling prices. We examine these ceiling prices in the context of the network services described above in the following sections.

A. Pricing of short term network services

With the posting of the PTDF by the SO for the entire year, n, the apparent operation of the electric power network is performed in the simplified linear regime. Suppose we apply the so-called DC load flow assumption as a method for linear simplification. Then, the expression for the flow on transmission line l, $F_l(\mathbf{Q_G}[k], \mathbf{Q_D}[k])$ is given by:

$$F_l(\mathbf{Q_G}[k], \mathbf{Q_D}[k]) = \sum_{g_i} H_{lg_i} Q_{g_i}[k] - \sum_{d_j} H_{ld_j} Q_{d_j}[k] \tag{19}$$

where H_{li} denotes the PTDF of line l with respect to bus i. The details of DC load flow simplification and the PTDF can be found in [10].

Given the DC load flow assumption, we develop the pricing of the residual transmission capacity by the SO. Let $\hat{\rho}_t[k]$ and $\mu_l[k]$ denote the *ex ante* flow tax and the congestion costs, respectively. As described above, the pricing of the short term network service is subject to the strict regulation according to the PCR scheme considered in this paper. Thus, at each hour k the SO may charge the market participants, in the spot market, for the network capacity on line l up to the transmission price, ρ_l, given by

$$\rho_l[k] = \begin{cases} \hat{\rho}_t[k] + \mu_l[k] & \text{if } \hat{\rho}_t[k] \le \hat{\rho}_t[n] \text{ and } \mu_\zeta[k] \le \mu_\zeta[n] \text{ for all } \zeta \text{ in the network,} \\ & \qquad \text{including } l \text{ itself} \\ \mu_l[k] & \text{otherwise, i.e. if } \mu_\zeta[k] > \mu_\zeta[n] \text{ for any } \zeta \text{ in the network,} \\ & \qquad \text{including } l \text{ itself} \end{cases} \tag{20}$$

where the ceiling prices for *ex ante* flow tax and the congestion costs are denoted by $\hat{\rho}_t[n]$ and $\mu_l[n]$ respectively, and $k = (n-1)T_T + 1, (n-1)T_T + 2, \cdots, nT_T$.

The revenue allowed to the TP at each hour k from the allocation of residual transmission capacity is given by

$$TR(\hat{\rho}_t[k], k) = \begin{cases} \sum_l \sum_{d_j} \left[(\hat{\rho}_t[k] + \mu_l[k]) \, (q^+_{l,d_j}[k] + q^+_{l,b_{ij}}[k]) \, (\hat{\rho}_t[k] - \mu_l[k]) + (q^-_{l,d_j}[k] + q^-_{l,b_{ij}}[k]) \right] \\ \qquad \text{if } \hat{\rho}_t[k] \le \hat{\rho}_t[n] \text{ and } \mu_l[k] \le \mu_l[n] \text{ for any } l \\ (1 - r_{penalty}) \sum_l \sum_{d_j} \mu_l[n] \left[(q^+_{l,d_j}[k] + q^+_{l,b_{ij}}[k]) - (q^-_{l,d_j}[k] + q^-_{l,b_{ij}}[k]) \right] \\ \qquad \text{otherwise, i.e. } \hat{\rho}_t = 0 \text{ and } \mu_l[k] > \mu_l[n] \text{ for any } l \end{cases} \tag{21}$$

under the PCR scheme here, where $r_{penalty}$ denotes the penalty rate imposed on the TP for violating the ceiling price of congestion charge. Thus, the maximum allowed revenue can be obtained by solving the following optimization problem:

$$\hat{\rho}^\star_t[k] = \begin{cases} \arg\max_{\hat{\rho}_t[k]} \sum_l \sum_{d_j} \left[(\hat{\rho}_t[k] + \mu^\star_l[k]) \, (q^+_{l,d_j}[k] + q^+_{l,b_{ij}}[k]) + (\hat{\rho}_t[k] - \mu^\star_l[k]) \, (q^-_{l,d_j}[k] + q^-_{l,b_{ij}}[k]) \right] \\ \qquad \text{if } \hat{\rho}_t[k] \le \hat{\rho}_t[n] \text{ and } \mu^\star_l[k] \le \mu_l[n] \text{ for any } l \\ 0 \qquad \text{otherwise, i.e. } \mu^\star_l[k] > \mu_l[n] \text{ for any } l \end{cases} \tag{22}$$

The optimization problem in Eq. (22) is complementary to the market clearing process at the spot market modeled in Eq. (17). We make another simplifying assumption on the shape of the demand and the supply functions, bid to the SO by the market participants, that they are linear, i.e.,

$$D_{d_j}(Q_{d_j}[k], k) = 2\alpha_{d_j}[k] \cdot Q_{d_j}[k] + \beta_{d_j}[k] \tag{23}$$

$$S_{g_i}(Q_{g_i}[k]) = 2a_{g_i} Q_{g_i}[k] + b_{g_i} \tag{24}$$

$$B_{d_j - g_i} = 2\alpha_{d_j - g_i}[k] \cdot Q_{d_j - g_i}[k] + \beta_{d_j - g_i}[k] \tag{25}$$

Then, Eq. (17) reduces to the following:

$$[\mathbf{Q_G}^\star[k], \mathbf{Q_D}^\star[k], \mathbf{Q_B}^\star[k]]' = \arg \max_{\mathbf{Q_G}[k], \mathbf{Q_D}[k], \mathbf{Q_B}[k]} \Bigg[\sum_{d_j} (\alpha_{d_j}[k] \cdot Q^2_{d_j}[k] + \beta_{d_j}[k] \cdot Q_{d_j}[k]) \tag{26}$$

$$- \sum_{d_j} \sum_l \hat{\rho}^\star_t[n] (q^+_{l,d_j}[k] + q^-_{l,d_j}[k]) - \sum_{g_i} (a_{g_i} Q^2_{g_i}[k] + b_{g_i} Q_{g_i}[k]) + \sum_{b_{ij}} (\alpha_{d_j - g_i}[k] \times$$

$$Q^2_{d_j - g_i}[k] + \beta_{d_j - g_i}[k] \cdot Q_{d_j - g_i}[k]) - \sum_{b_{ij}} \sum_l \hat{\rho}^\star_t[n] (q^+_{l,b_{ij}}[k] + q^-_{l,b_{ij}}[k]) \Bigg]$$

subject to

$$\sum_{g_i} Q_{g_i}[k] = \sum_{d_j} Q_{d_j}[k] : \qquad \lambda[k] \tag{27}$$

$$Q_{g_i}^{\min}[k] \le Q_{g_i}[k] \le Q_{g_i}^{\max}[k] : \qquad \eta_{g_i}[k] \tag{28}$$

$$\sum_{g_i} H_{lg_i} Q_{g_i}[k] - \sum_{d_j} H_{ld_j} Q_{d_j}[k] + \sum_{b_{ij}} (H_{lg_i} - H_{ld_j}) Q_{b_{ij}}[k] + F_{l,int}[k] \le F_l^{\max}[n] : \qquad \mu_l[k] \tag{29}$$

where $F_{l,int}[k]$ are the portion of transmission capacity allocated previously to the participants with physical transmission rights, and the Lagrangian multiplier $\mu_l^\star[k]$ matches the congestion cost in Eq. (22). We apply the DC load flow assumptions to the flow constraint in Ineq. (29).

It is clear from Eqs. (20) and (21) that there may be a significant difference between the revenue collected by the SO and the revenue received by the ITC when the congestion cost, for constraining the flows within the operationally acceptable limits, $F_l^{\max}[n]$, exceeds the corresponding ceiling price. This difference is returned through some form of rebate mechanism[11] to the market participants in the spot market only, since the PCR scheme, by definition, is intended to protect the market participants from being over-charged by the TP. The market participants who acquired their network capacity through the intermediate term transmission contracts are excluded from the rebate process since those contracts are sold without any regulation thus without any protection. Note that the demand and the supply functions in Eq. (26) represent the bids submitted to the SO in the spot market for energy.

B. Pricing of intermediate term network services

Suppose the ITC carries out the computation of the optimization problem given in Eq. (22) and solves for the price of network capacity on line l using Eq. (20) but from the expected value sense for an entire year n, i.e.

$$\hat{\rho}_t^\star[k] = \begin{cases} \arg\max_{\hat{\rho}_t[k]} \sum_l \sum_{d_j} \mathcal{E}\left\{ (\hat{\rho}_t[k] + \mu_l^\star[k]) \, (q_{l,d_j}^+[k] + q_{l,b_{ij}}^+[k]) + (\hat{\rho}_t[k] - \mu_l^\star[k]) \, (q_{l,d_j}^-[k] + q_{l,b_{ij}}^-[k]) \right\} \\ \qquad \text{if } \mathcal{E}\{\hat{\rho}_t[k]\} \le \hat{\rho}_t[n] \text{ and } \mathcal{E}\{\mu_l^\star[k]\} \le \mu_l[n] \text{ for any } l \\ 0 \qquad \text{otherwise, i.e. } \mathcal{E}\{\mu_l^\star[k]\} > \mu_l[n] \text{ for any } l \end{cases} \tag{30}$$

$$[\mathbf{Q_G}^\star[k], \mathbf{Q_D}^\star[k], \mathbf{Q_B}^\star[k]]' = \arg \max_{\mathbf{Q_G}[k], \mathbf{Q_D}[k], \mathbf{Q_B}[k]} \mathcal{E}\left\{ \sum_{d_j} (\alpha_{d_j}[k] \cdot Q_{d_j}^2[k] + \beta_{d_j}[k] \cdot Q_{d_j}[k]) \right. \tag{31}$$

[11] The actual "optimal" process for this rebate mechanism is beyond the scope of this paper.

$$
\begin{aligned}
&- \sum_{d_j} \sum_{l} \hat{\rho}_t^{\star}[n](q_{l,d_j}^{+}[k] + q_{l,d_j}^{-}[k]) - \sum_{g_i}(a_{g_i} Q_{g_i}^2[k] + b_{g_i} Q_{g_i}[k]) \\
&+ \sum_{b_{ij}} (\alpha_{d_j - g_i}[k] \cdot Q_{d_j-g_i}^2[k] + \beta_{d_j-g_i}[k] \cdot Q_{d_j-g_i}[k]) \\
&\left. - \sum_{b_{ij}} \sum_{l} \hat{\rho}_t^{\star}[n](q_{l,b_{ij}}^{+}[k] + q_{l,b_{ij}}^{-}[k]) \right\}
\end{aligned}
$$

for $k = (n-1)T_T + 1, (n-1)T_T + 2, \cdots, nT_T$ and subject to

$$\sum_{g_i} \mathcal{E}\left\{Q_{g_i}[k]\right\} = \sum_{d_j} \mathcal{E}\left\{Q_{d_j}[k]\right\} : \qquad \mathcal{E}\left\{\lambda[k]\right\} \tag{32}$$

$$\mathcal{E}\left\{Q_{g_i}^{\min}[k]\right\} \leq \mathcal{E}\left\{Q_{g_i}[k]\right\} \leq \mathcal{E}\left\{Q_{g_i}^{\max}[k]\right\} : \qquad \mathcal{E}\left\{\eta_{g_i}[k]\right\} \tag{33}$$

$$\sum_{g_i} H_{lg_i} \mathcal{E}\left\{Q_{g_i}[k]\right\} - \sum_{d_j} H_{ld_j} \mathcal{E}\left\{Q_{d_j}[k]\right\} + \sum_{b_{ij}} (H_{lg_i} - H_{ld_j}) \mathcal{E}\left\{Q_{b_{ij}}[k]\right\} + \mathcal{E}\left\{F_{l,int}[k]\right\} \leq F_l^{\max}[n] \tag{34}$$

$$: \qquad \mathcal{E}\left\{\mu_l[k]\right\}$$

Then, for any hour k, the expected price for network capacity is given by:

$$\mathcal{E}\{\rho_l[k]\} = \mathcal{E}\{\hat{\rho}_t^{\star}[k] + \mu_l[k]\} \tag{35}$$

Consider pricing, $\rho_l(t_s, t_e)$, of the network capacity on line l for the intermediate term transmission contracts over the duration of t_s and t_e. Based on the expression in Eq. (35) the intermediate term transmission contracts need to be priced for purchase at $k = t_e$ as the following:

$$\rho_l(t_s, t_e) = \sum_{k=t_s}^{t_e} (1-\xi)^{k-t_e} \mathcal{E}\{\rho_l[k]\} \tag{36}$$

where $\rho_l[k]$ is computed from the expression in Eq. (35). This is because any other pricing mechanism yields a risk-free opportunity for profit known as *arbitrage* in economics [8] to some entities at the expense of other entities. The anticipated behavior by the entities facing the expenses prevents such opportunities, thus leads to the pricing of the intermediate term transmission contract to be given by the expression in Eq. (36). This is stated more formally in the following lemma.

Lemma 1: The profit maximizing ITC charges to the profit maximizing market participants for the intermediate transmission contracts at the price given by Eq. (36).

Proof:

Suppose the actual price of the intermediate term transmission contracts, $p_l^+(t_s, t_e)$, is lower than the price given in Eq. (36). Then, the market participants are presented with an arbitrage opportunity since the holders of the intermediate term transmission contracts are entitled to the prevailing prices of network capacity for the cases where the network capacity is not used for physical exchanges by the holders. The holders gain at the expense of the ITC, the difference between the price that is paid and the price that is prevailing in the spot market over the duration of the contract, $[t_s, t_e]$, i.e.,

$$\pi = \sum_l \left(\rho_l^+(t_s, t_e) - p_l^+(t_s, t_e) \cdot \sum_{k=t_s}^{t_e} F_{l,financial}[k] \right) \tag{37}$$

where $F_{l,financial}[k]$ is the network capacity not utilized after having been purchased through the intermediate term transmission contracts. Plus, given this arbitrage opportunity the spot market participants are likely to enter into the intermediate term transmission contracts so that they reduce their cost for transmission charges. As more spot market users enter into the contracts at the transmission price lower than the prevailing price at the spot market, the revenue collected by the ITC through the SO becomes smaller as well. Therefore, this results in the profit maximizing ITC increasing the price for the intermediate term transmission contracts.

Suppose the actual price of the intermediate term transmission contracts, $p_l^+(t_s, t_e)$, is higher than the price given in Eq. (36). Then, the market participants are again presented with an arbitrage opportunity since the marketers may offer to sell financial transmission contracts at a little lower price than $p_l^+(t_s, t_e)$ but still higher than the price given in Eq. (36) and may receive the difference for profit. Assuming that there is a demand for the intermediate term transmission contracts even at the high price, the financial transmission contracts issued by the marketers reduce the profits for ITC, and thus this results in the profit maximizing ITC decreasing the price for the intermediate term transmission contracts.

Therefore, the price for the intermediate term transmission contract is set by the expression in Eq. (36). ■

Given that the pricing of the intermediate term transmission contracts approaches the pricing at the spot market for energy, the equilibrium price computed by solving the optimization problem in Eq. (31) is the same as the solution including the overall market activities. Since all of the physical exchanges of electricity among the market participants is determined through purchasing the physical transmission rights in the form of the intermediate term transmission contract and through trading in the spot market, at the equilibrium, from the expected value sense, the consumption and the generation of electricity by the market participants revealed through Eq. (31) at their entirety need to be equal to the corresponding energy usage computed including the overall market activities (and not just in the spot market).

The above implies that in order to compute the prices to be charged for the intermediate term transmission contracts, the ITC may solve the optimization problem including the overall market activities while estimating the demand and the supply functions of the loads and generators, $D_{d_j}(Q_{d_j}[k], k)$ and $S_{g_i}(Q_{g_i}[k], k)$ respectively, in their entirety, instead of solving the optimization problem in Eq. (31) while estimating the demand and the supply functions in the spot market for energy, $\alpha_{d_j}[k] \cdot Q^2_{d_j}[k] + \beta_{d_j}[k] \cdot Q_{d_j}[k]$ and $a_{g_i} Q^2_{g_i}[k] + b_{g_i} Q_{g_i}[k]$ respectively, separated from the bilateral preference function, $\alpha_{d_j - g_i}[k] \cdot Q^2_{d_j - g_i}[k] + \beta_{d_j - g_i}[k] \cdot Q_{d_j - g_i}[k]$ and the portion of transmission capacity allocated previously to the participants with physical transmission rights, $F_{l,int}[k]$. This reduces the computational effort considerably when solving the optimization problem in Eq. (31) over a year n for $k = (n-1)T_T + 1, (n-1)T_T + 2, \cdots, nT_T$.

A further reduction in the computational effort may be made if the demand at each load is considered inelastic. In the following section we suggests an approximate computational method, known as the modified probabilistic optimal power flow (m-POPF), for pricing intermediate term network services [12].

B.1 Approximate computational method for pricing intermediate term network services

In [2] probabilistic optimal power flow (POPF) is introduced as a tool for evaluating the likely use of transmission network. Using this novel method binding transmission limits can be identified under normal operating conditions with the probability associated with the binding limits. The value of the network capacity can be then deduced based on the result of solving POPF.

POPF uses a Monte Carlo-based method to efficiently solve optimal power flow (OPF) taking into account transmission line flow limits and generation capacity constraints over the possible range of load demand. The complete formulation of the OPF is given as the following:

$$\mathbf{Q_G}^{\star}[k] = \arg \min_{\mathbf{Q_G}[k]} \sum_{g_i} (a_{g_i} Q_{g_i}^2[k] + b_{g_i} Q_{g_i}[k]) \tag{38}$$

$$\sum_{g_i} Q_{g_i}[k] = \sum_{d_j} Q_{d_j}[k] : \qquad \lambda[k] \tag{39}$$

$$Q_{g_i}^{\min}[k] \leq Q_{g_i}[k] \leq Q_{g_i}^{\max}[k] : \qquad \eta_{g_i}[k] \tag{40}$$

$$\sum_{g_i} H_{lg_i} Q_{g_i}[k] - \sum_{d_j} H_{ld_j} Q_{d_j}[k] \leq F_l^{\max}[n] : \qquad \mu_l[k] \tag{41}$$

where $Q_{d_j}[k]$ is assumed to be given.

First, we construct the probability density function of the system demand. Traditional utilities have published what is referred to as load duration curve that depicts the cumulative probability of system load as shown in Figure 6 [12]. The probability density function of

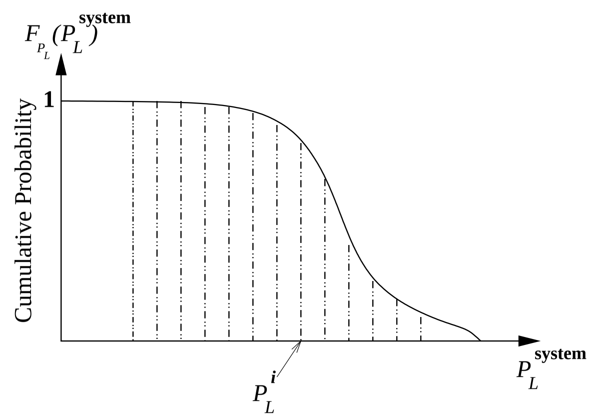

Fig. 6. Discretized Load Duration Curve

system load, f_{Q_D} is then computed by taking the first derivative of the load duration curve as follows:

$$f_{Q_D}(Q_D^i) = \left(\frac{dF_{Q_D}}{dQ_D} \right)_{Q_D = Q_D^i} \tag{42}$$

where $Q_D = \sum_{d_j} Q_{d_j}$.

Given the probability density function, individual load pattern is computed along the incremental increase in system load starting from its minimum. Because of metering problem, the probabilistic modeling of individual load pattern may not be easily inferable in real-life systems. In [12] an approach is suggested to cope with this problem. The approach finds the peak, off-peak and normal individual load patterns and their corresponding range of system load as shown in Figure 7. Employing fuzzy logic, these patterns are meshed to create

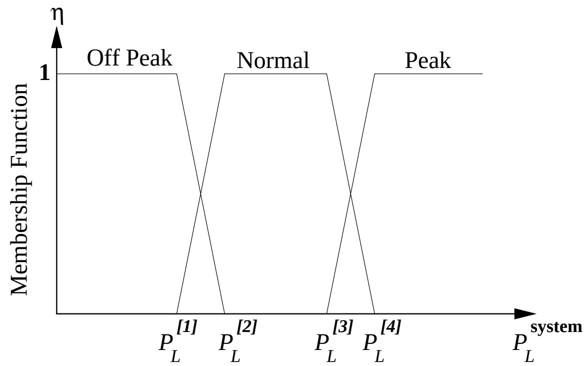

Fig. 7. Membership Functions for Individual Load Pattern

typical individual load patterns which match the probability density function of system load as follows, $Q_D^{[k]} = Q_D^{\text{system}}(k)$:

$$\mathbf{Q_D}[k] = \left(\eta^{[N]}\frac{Q_{d_j}^{[N]}}{1^T Q_L^{[N]}} + \eta^{[OP]}\frac{Q_{d_j}^{[OP]}}{1^T Q_L^{[OP]}} + \eta^{[PK]}\frac{Q_{d_j}^{[PK]}}{1^T Q_L^{[PK]}}\right) \tag{43}$$

Finally, OPF is solved as in Eq. (38) using individual load patterns along the system load from the minimum to the maximum. Computing flows on transmission lines after OPF and fitting the flows against probability density function yield cumulative probability of transmission system usage.

$$\begin{aligned} \text{Prob}\left\{F_l \leq \bar{F}_l\right\} &= \text{Prob}\left\{F_l\left(\mathbf{Q}^\star_{\mathbf{G}}(Q_D^i)\right) \leq \bar{F}_l\right\} \\ &= \int_0^{\bar{F}_l} f_{Q_D}(Q_D^i) dF_l \end{aligned} \tag{44}$$

This result is then used to derive the value of transmission.

Similar pricing mechanisms may be applied for offering the long term network services.

VII. Conclusion

The development of new market tools for operating the transmission system becomes essential as the ITC moves into the active phase of management. In this phase the ITC is required to make complex business decisions over a wide range of time scales: long-term, intermediate-term and short-term.

The long term decisions deal with the transmission system expansion. A fundamental question is related to computing the impact of the future demand on the system constraints and making system reinforcements in order to meet this demand. It is shown in the proposed transmission rate design that the investment cost is not directly affected by congestion rent at the spot market due to the high fixed cost element. Thus, no market tool for investment decision is required for the ITC based on spot market activities. Even when there is a significant congestion sustained over a long period of the time, the investment needed for relieving this congestion is a decision to be made by the regulator upon reviewing the performance of the ITC since the authority to modify the transmission rate lies on the regulator and not on the ITC. Typically the bilateral trades take place over an extended period and thus provide adequate revenue sources for investment recovery. The new market tools in long term project the demand in bilateral trades and in long term transmission contracts. The new market tools should make this projection based on the historical patterns on the users in subscribing into bilateral transactions sometime supported by long term transmission contracts, as well as the expected changes in customer basis. An investment into a new efficient generator by a participant is likely to follow by a request for implementing bilateral trades since such investment requires a steady flow of revenue. The better projection that the new market tools can produce, the more prudent investment the ITC makes and subsequently the higher earnings.

The intermediate term decisions deal with pricing intermediate term transmission contracts. This is perhaps the most difficult task by the ITC since the success of the ITC as an independent market entity depends on its ability to function as a risk taker.

There are three aspects to consider in the pricing. The first is refining the projection of bilateral trades from the long term market decision tool. Although only the aggregate volume is important in making investment decisions, the short-term decision requires an accurate projection of the locational and temporal patterns and the opportunity costs for each bilateral transaction. Over time, the market tool in this time scale can discover the patterns and the costs by extrapolating from previous seasonal behavior of the participants. The second is the valuation of intermediate term transmission contracts given the specifications of a bilateral contract as described in the paper. Finally, the third aspect of pricing is relating the decisions in providing the intermediate term transmission contracts within spot market activities. The ITC and SO are required, therefore, to solve for the optimal balance between bilateral trades and spot market transactions in terms of its profit. For instance, if the ITC deviates from this optimal and lean too much on the bilateral trades, there is an expected deterioration in the short term efficiency for which the ITC is responsible through the strict rate design. If the ITC, on the other hand, relies heavily on the spot market while neglecting the bilateral trades, the ITC may not be able to function as an active market entity. There are very few market tools available for solving this type of problem in other financial markets, but some active studies are underway.

The short term decisions involve computing a combined optimization problem for minimizing intermediate term transmission contract defaults while maximizing the spot market throughput. These two are conflicting objectives and thus requires defining some offsetting weights when solving the combined optimization problem. The ITC can expand the conventional OPF tools as the new market tool needed for approaching the problem.

As the industry moves into the more mature stage of deregulation, the role of TP becomes more important. The new market tools described above are only the minimal changes required in the way the TP conducts its business as an active market participant, the ITC. It is, therefore, critical to build the tools that are consistent with the way they function over different time scales as well as with the other new business-oriented tools that are used by the participants.

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